Electricity Report

AUSTRALIAN ENERGY REGULATOR

22 - 28 January 2017

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 22 – 28 January 2017.

Figure 1: Spot price by region ($/MWh)

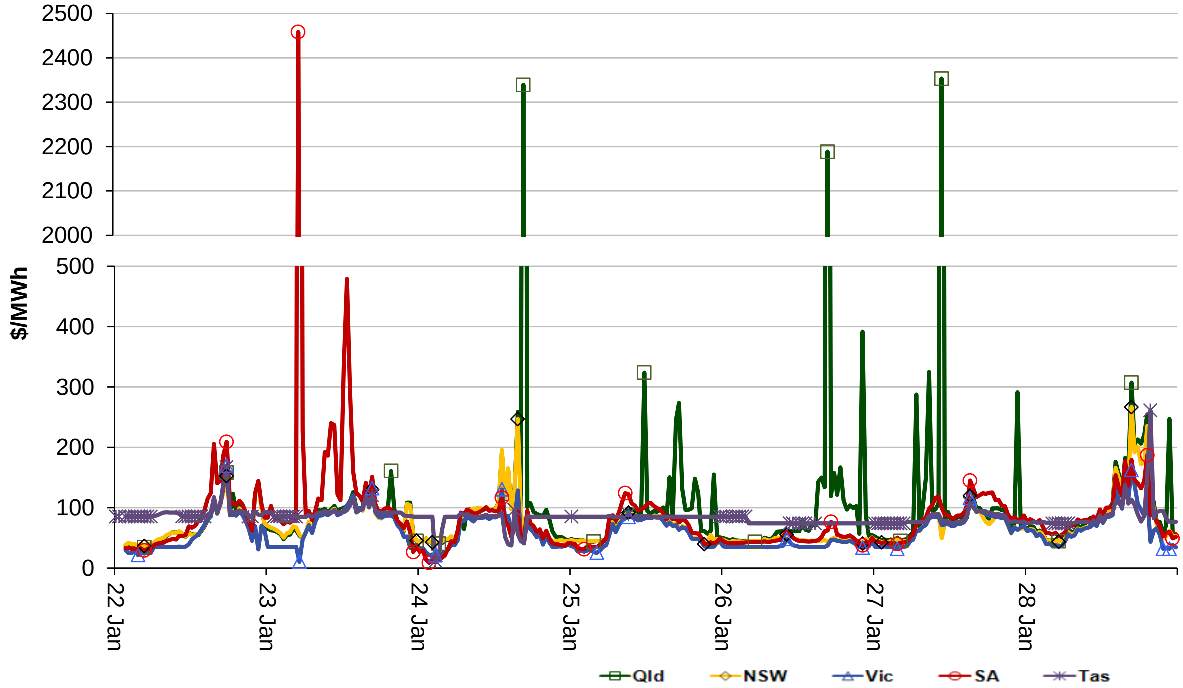


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

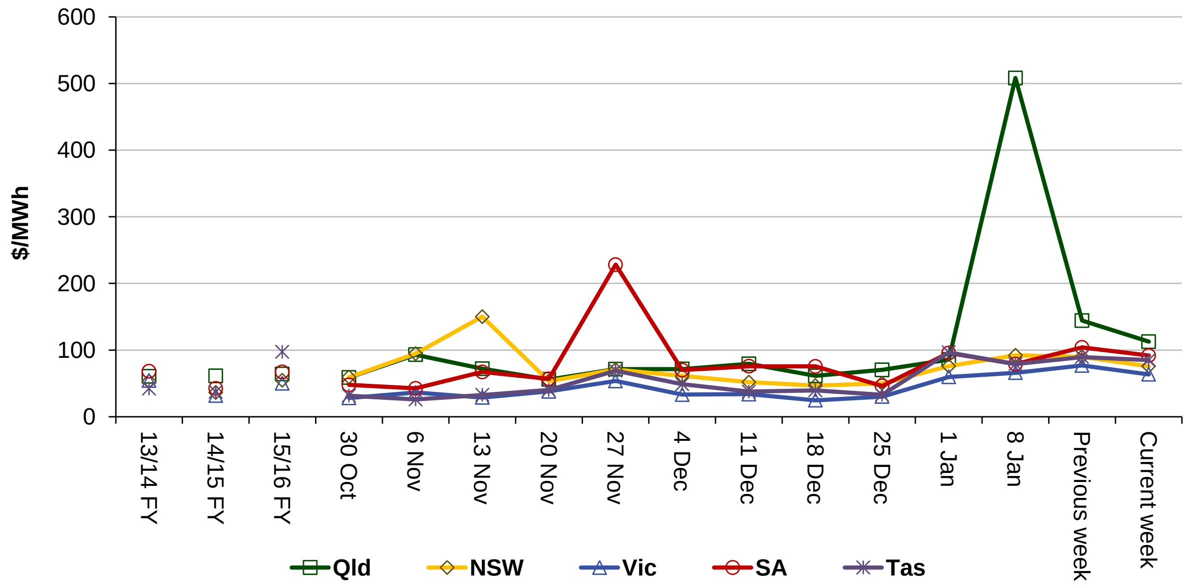


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	113	76	64	92	85
15-16 financial YTD	45	46	44	64	64
16-17 financial YTD	83	64	47	104	52

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 183 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2016 of 273 counts and the average in 2015 of 133. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	10	43	0	4
% of total below forecast	26	13	0	4

Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns

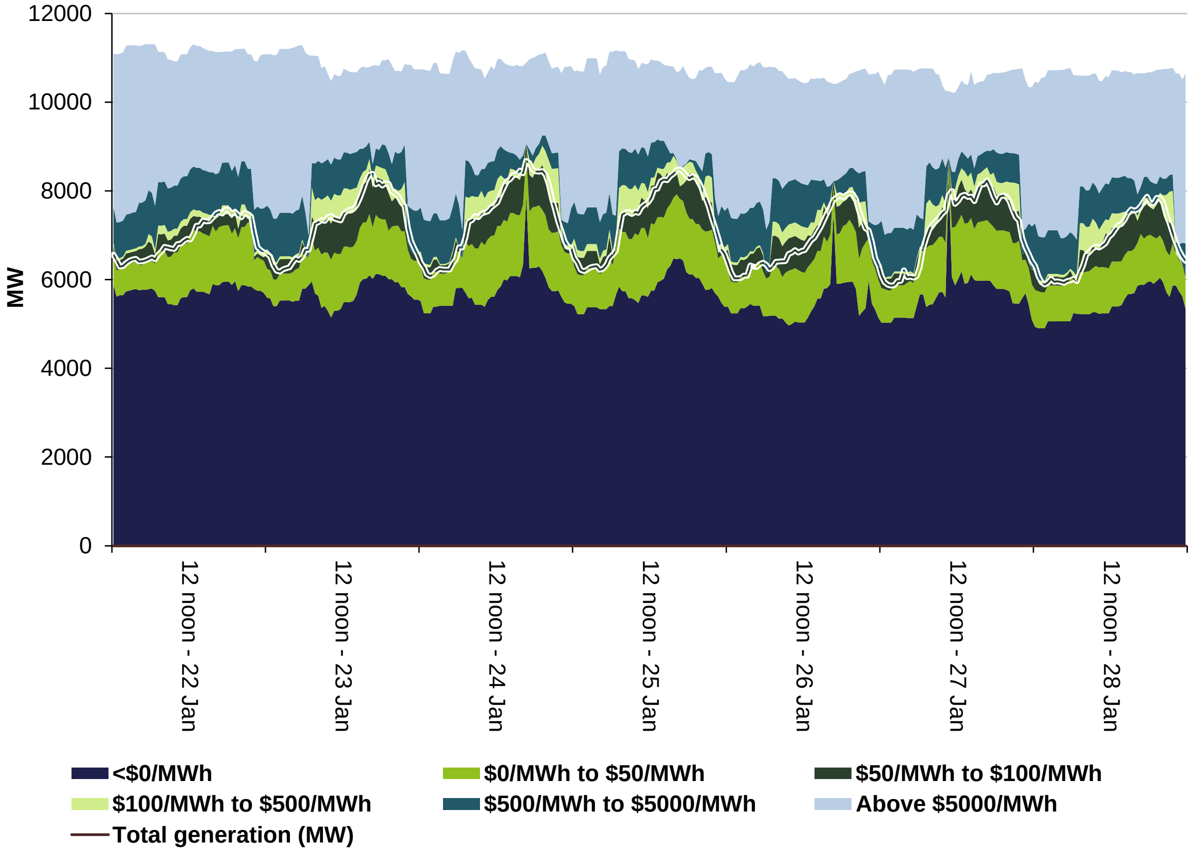


Figure 4: New South Wales generation and bidding patterns

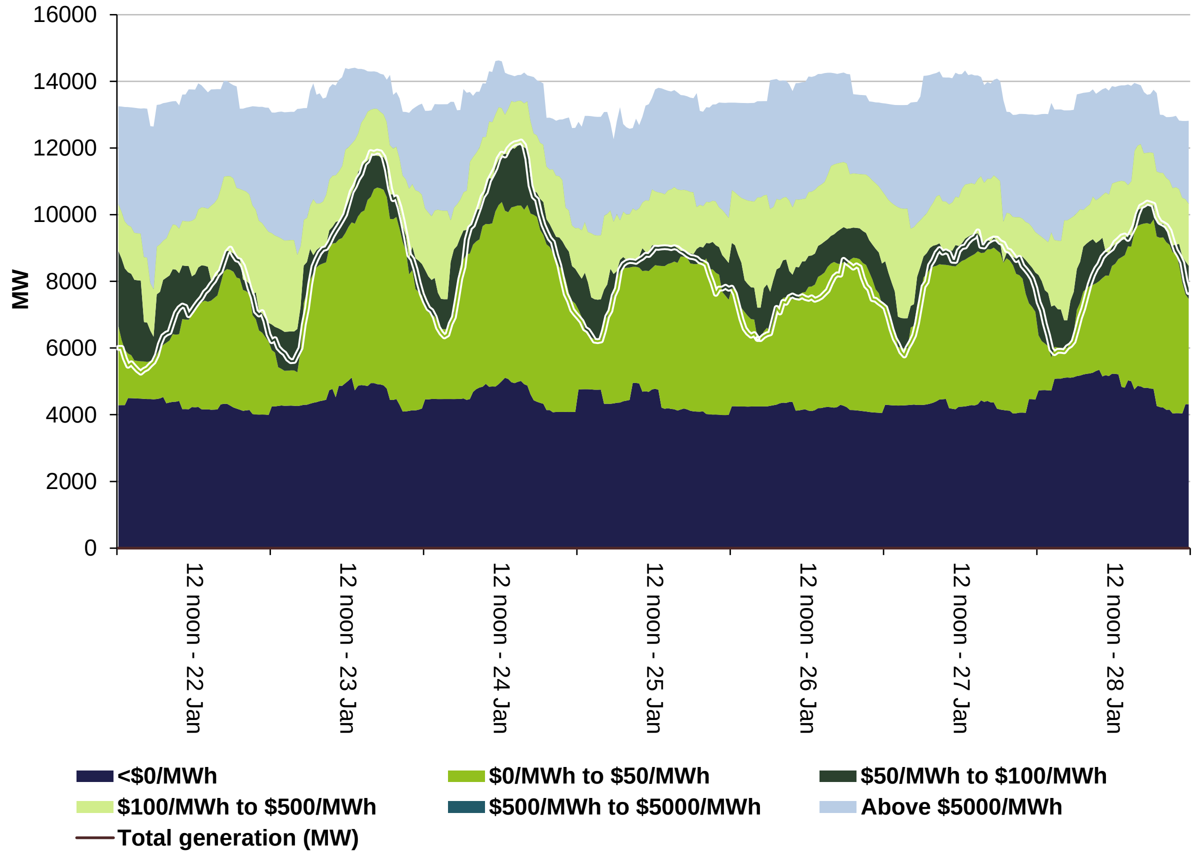


Figure 5: Victoria generation and bidding patterns

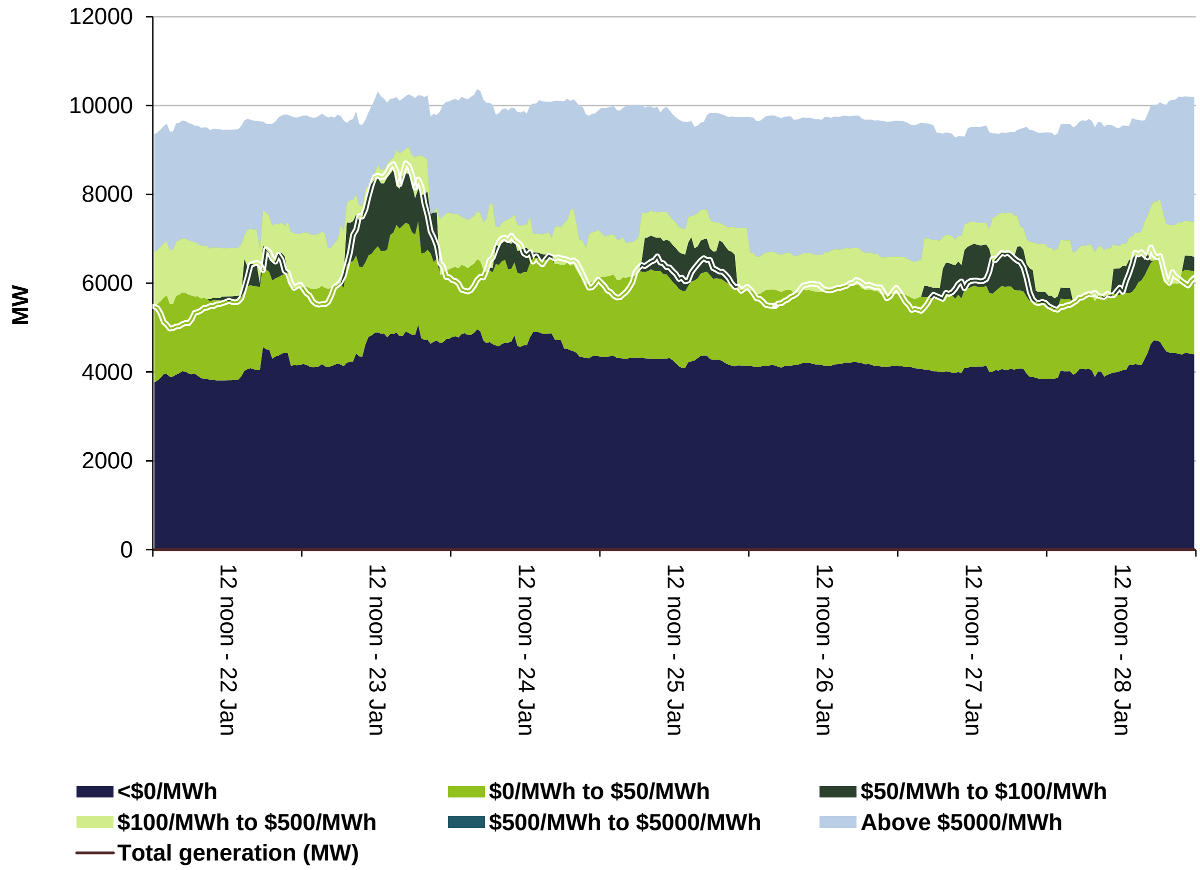


Figure 6: South Australia generation and bidding patterns

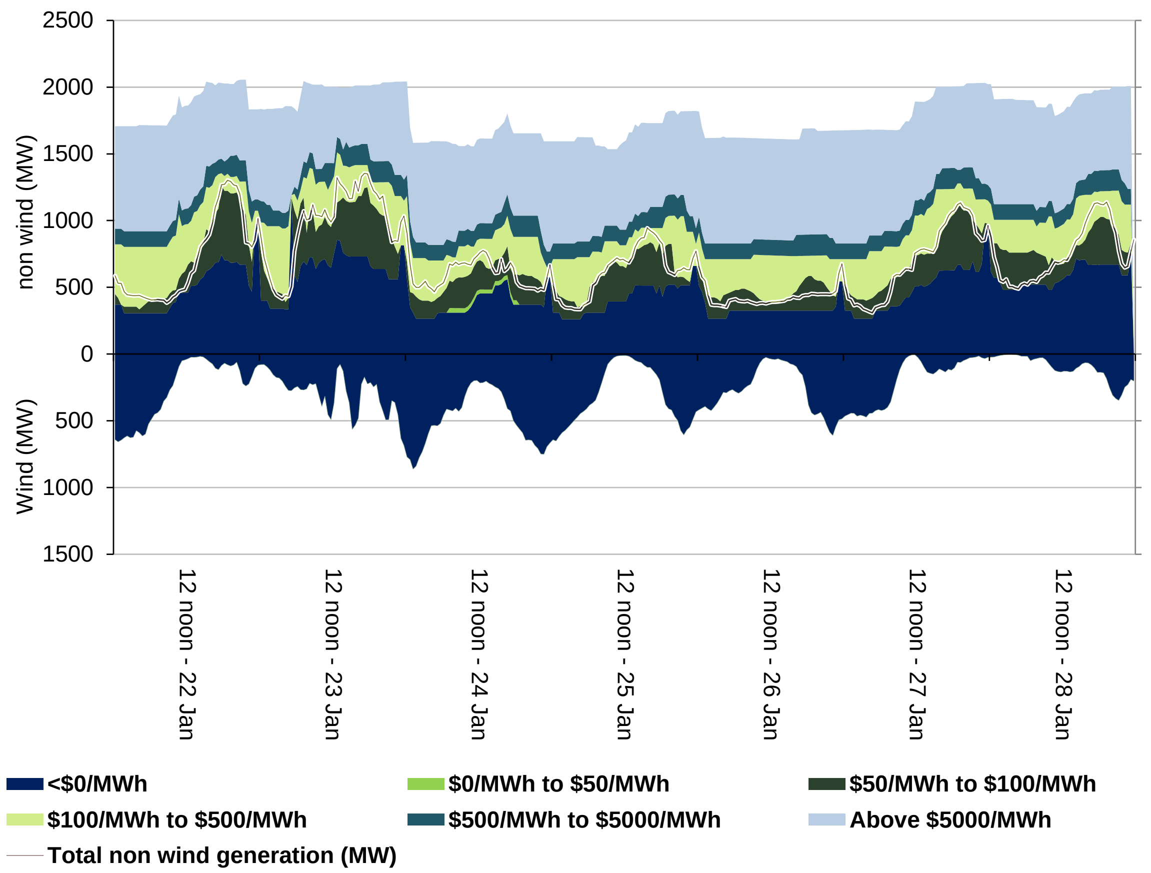
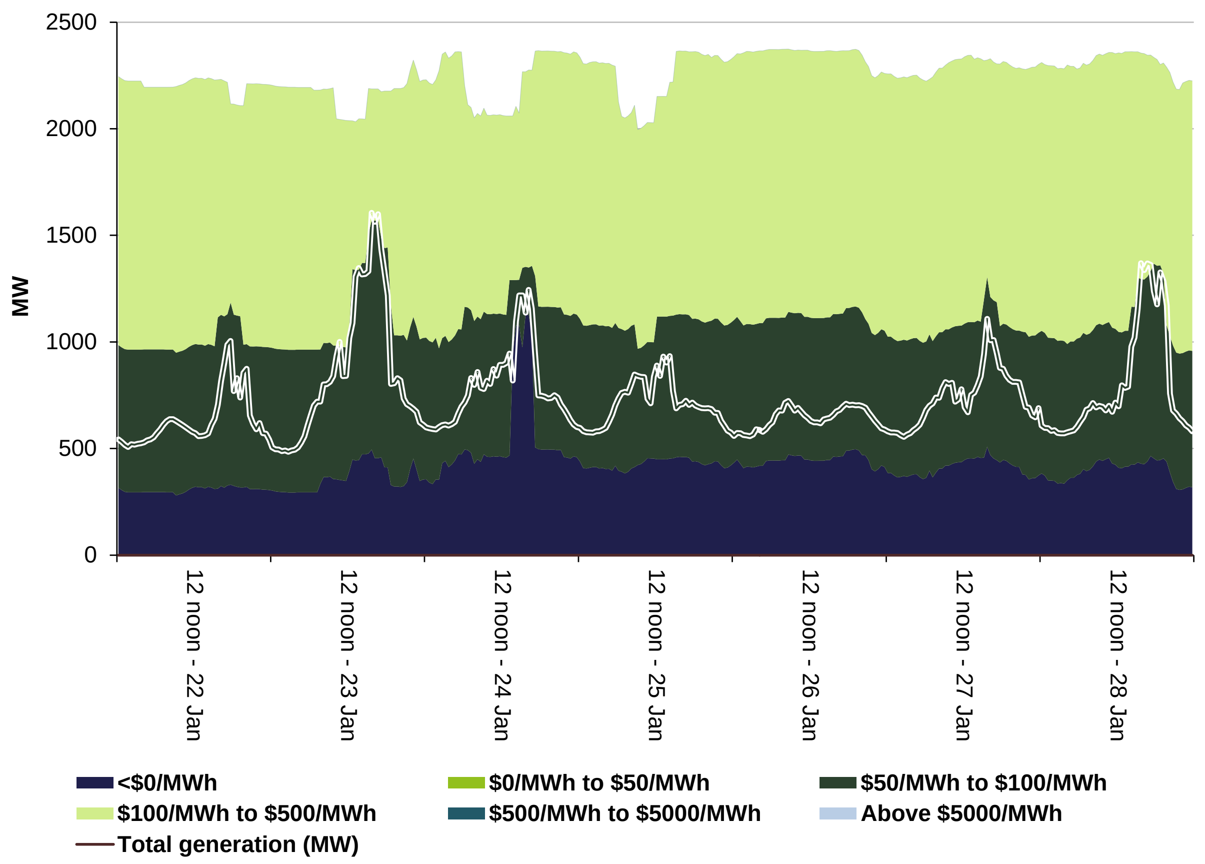


Figure 7: Tasmania generation and bidding patterns



Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

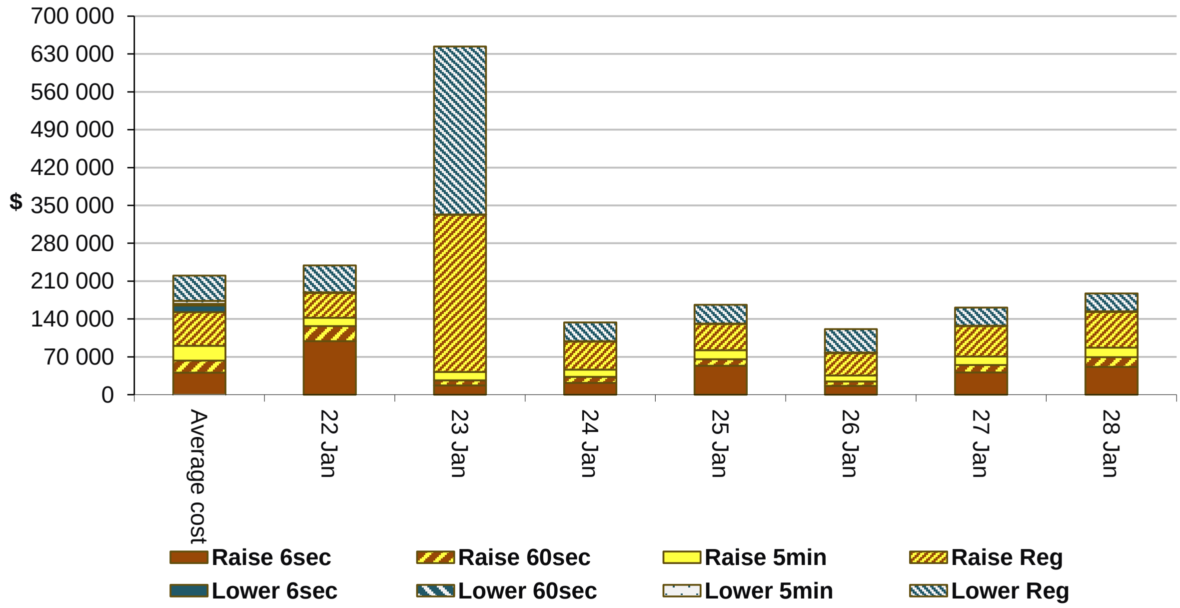
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a "causer pays" basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $1 246 000 or around less than one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $407 500 or around three per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

Figure 8: Daily frequency control ancillary service cost



On 23 January an unplanned outage of the APD to Heywood to Mortlake No. 2 500 kV line left South Australia on a single contingency. If the remaining line is lost, South Australia would separated from the rest of the NEM. AEMO invoked constraints requiring 35 MW of local regulation services. The price of regulation services in South Australia exceeded $5000/MW for three trading intervals (two for lower services and one for raise services). The total cost was around $0.55 million.

Detailed market analysis of significant price events

Queensland

There were four occasions where the spot price in Queensland was greater than three times the Queensland weekly average price of $113/MWh and above $250/MWh.

Tuesday, 24 January

Table 3: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5 pm	2339.11	1405.69	2150.30	8363	8254	8184	10 890	11 130	11 260

Conditions at the time saw demand over 100 MW higher and availability 240 MW lower than that forecast four hours ahead. Rebidding from high to low prices between four and 12 hours ahead of dispatch caused the four hour forecast price to drop.

In the four hours leading up to the 5 pm trading interval around 240 MW of predominately low priced capacity was removed. For the 4.35 pm dispatch interval, demand increased by 37 MW and net imports from New South Wales decreased by 45 MW. With limited amounts of capacity priced between $370/MWh and $13 800/MWh and cheaper generation ramp rate limited or requiring more than five minutes to start, the small increase in required generation resulted in the price reaching $13 800/MWh. The price then decreased to between $25/MWh and $63/MWh for the remainder of the trading interval due to participants rebidding capacity from high to low prices.

Thursday, 26 January

Table 4: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5 pm	2188.39	1405.69	1405.69	7864	7744	7721	10 425	10 595	11 129
10.30 pm	391.70	2150.10	2150.10	6943	7035	6949	10 714	10 639	10 761

For the 5 pm trading interval, conditions at the time saw demand 120 MW higher than forecast and availability 170 MW lower than forecast four hours ahead.

At 4.50 pm, demand increased by 132 MW. With only a small amount of capacity priced between $149/MWh and $12 499/MWh that was ramp rate limited or required more than five minutes to start, the price went to around $12 500/MWh for one dispatch interval. The price then decreased to less than $45/MWh for the rest of the trading interval as demand decreased and lower priced generation was no longer limited.

At 10.05 pm the dispatch price was $2150/MWh. In response to the high price, around 600 MW of capacity was rebid to lower prices resulting in the lower than forecast price for the 10.30 pm trading interval.

Friday, 27 January

Table 5: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
11 am	2353.04	254.11	98.93	7523	7362	7293	10 227	10 608	10 686

Conditions at the time saw demand 161 MW higher and availability around 380 MW lower than forecast four hours ahead.

At 10.35 am demand increased by 75 MW and with low priced generation either fully dispatched or ramp rate limited the price increased to $14 000/MWh. The price then returned to previous levels as demand decreased and participants rebid around 260 MW of capacity from high to low prices.

New South Wales

There was one occasion where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $76/MWh and above $250/MWh.

Saturday, 28 January

Table 6: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5 pm	266.76	247.96	96.00	10 977	10 366	10 027	13 779	13 999	14 324

Conditions at the time saw the spot price close to that forecast four hours ahead.

South Australia

There were four occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $92/MWh and above $250/MWh.

Monday, 23 January

Table 7: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5.30 am	2458.04	74.75	41.91	1322	1373	1331	2131	2217	2346
12.30 pm	331.60	124.99	103.22	1987	1853	1796	2372	2536	2635
1 pm	478.89	124.99	104.85	2035	1932	1853	2109	2543	2655
1.30 pm	294.80	151.12	125.65	1910	1979	1895	2077	2496	2603

For the 5.30 am trading interval, demand was close to forecast and availability was around 90 MW lower than that forecast four hours ahead. At 5.08 am, an unplanned outage occurred on the APD to Heywood to Mortlake No. 2 500 kV line which resulted in the Heywood interconnector being constrained down by around 290 MW for the 5.20 am trading interval. High priced capacity was then required to make up for the reduction in imports. As a result, the price reached $14 000/MWh for one dispatch interval.

For the 12.30 pm, 1 pm and 1.30 pm trading intervals, demand was between 70 MW lower and 134 MW higher than that forecast four hours ahead. Availability was between 86 MW and 434 MW lower than that forecast four hours ahead, mainly due to a 400 MW decrease in semi-scheduled wind output.

As a result higher priced generation was dispatched and resulted in the higher than forecast prices.

Tasmania

There was one occasion where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $85/MWh and above $250/MWh.

Saturday, 28 January

Table 8: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
8 pm	261.16	87.41	94.47	1066	1109	1112	2289	2339	2305

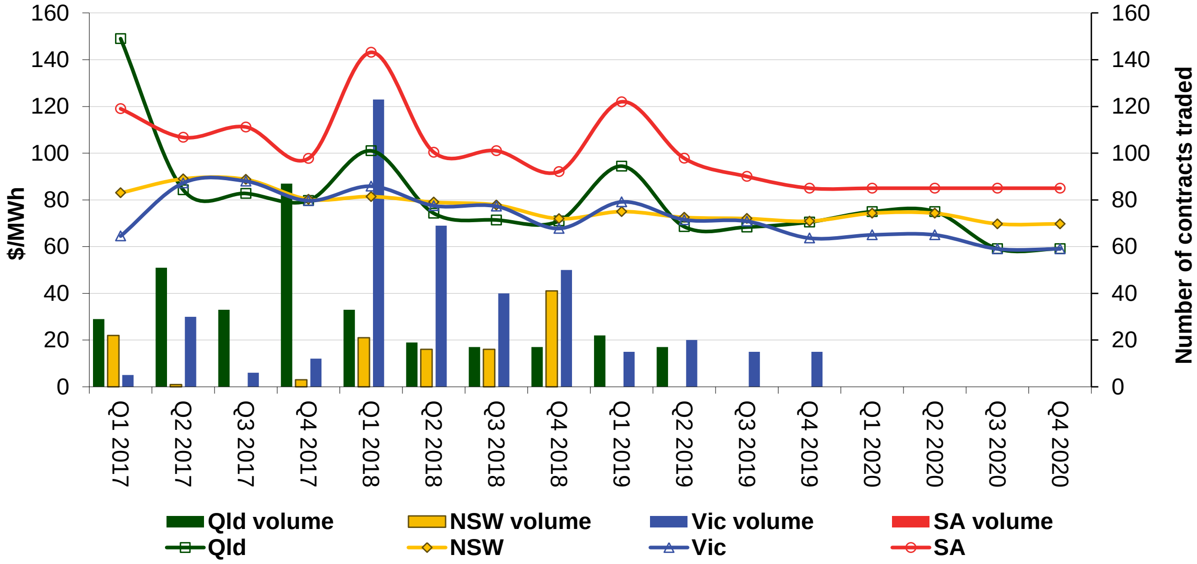
Both demand and availability were around 50 MW lower than that forecast four hours ahead.

At 7.25 pm, effective from 7.35 pm, Hydro Tasmania rebid 102 MW of capacity at John Butters rebid from $101/MWh to $349/MWh. The reason given was “1924A P5 Basslink flow > forecast”. As a result the dispatch price increased to $349/MWh and remained there for the first four dispatch intervals of the 8 pm trading interval.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

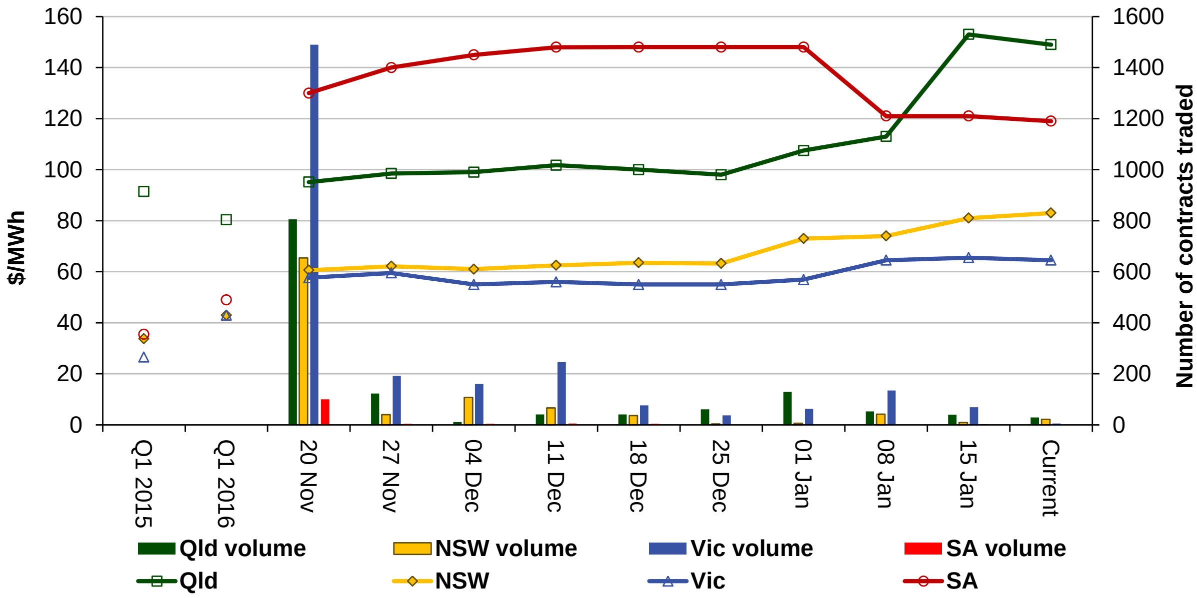
Figure 9: Quarterly base future prices Q1 2017 – Q4 2020



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2017 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2017 base contracts over the past 10 weeks (and the past 2 years)



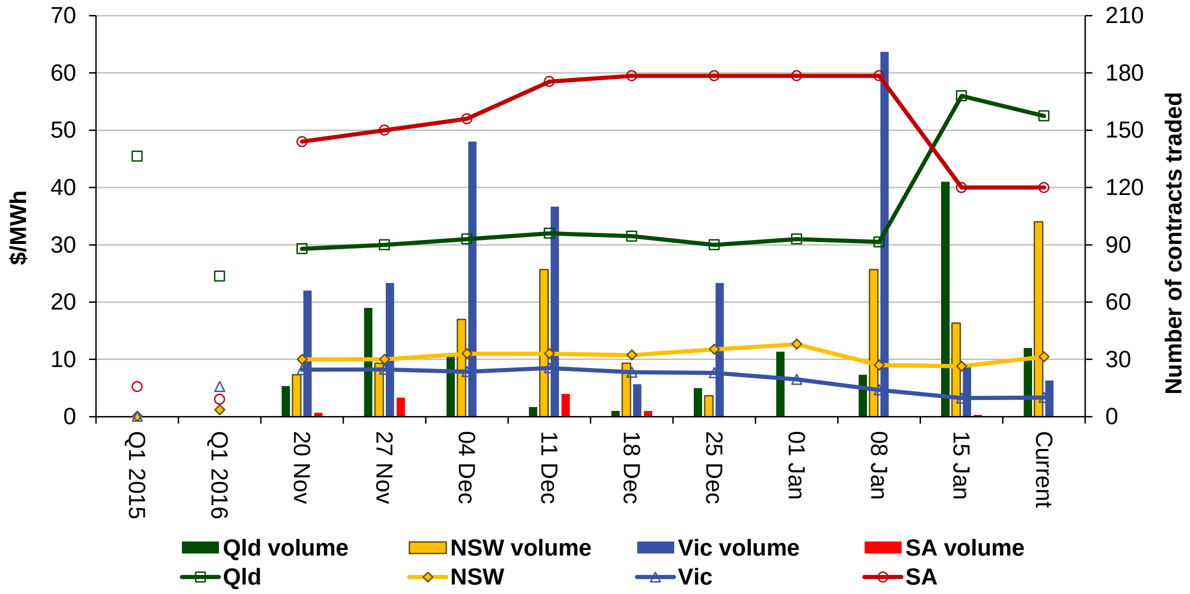
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics] section of our website.

Figure 11 shows how the price for each regional quarter 1 2017 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2015 and quarter 1 2016 prices are also shown.

Figure 11: Price of Q1 2017 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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